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SIMULATION OF PRODUCTION FROM WELLS WITH HORIZONTAL LATERALS

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SIMULATION OF PRODUCTION FROM WELLS WITH HORIZONTAL LATERALS

By Ming-Ming Chang*

SUMMARY

A literature survey of horizontal well studies was conducted before the development of a horizontal well model for the numerical simulator. A subroutine was added in the BOAST simulator to read the horizontal well information. The existing subroutine, which relates flow rate and wellbore pressure, was modified so that the horizontal wellbore pressure can be calculated at the option of infinite conductivity under the rate constraint. The developed well model was successfully checked against the published analytical formulas of transient wellbore pressure derived for the horizontal well. To verify the application of the horizontal well model, a field simulation of horizontal well production is being conducted with the data collected from a volatile oilfield in the State of New Mexico.

OBJECTIVE

The objective of this work is to develop the means for predicting the potential production rate and oil recovery for wells with horizontal/slanted laterals and to compare the results with actual field production data.

INTRODUCTION

Drilling horizontal wells to increase productivity has proved to be successful in several field tests. The productivity of horizontal wells has been studied using an analytical formula in the pseudo steady approximation and more recently in the transient pressure response. Because of the limiting conditions assumed for developing the above analytical formulas, the development of a horizontal well model in a numerical simulator for a general reservoir study appears to be important.

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LITERATURE SURVEY

A literature survey of horizontal well studies was completed. Analytical solutions for horizontal wells were collected as benchmarks for numerical simulations to be conducted. Technical papers about models for reservoir simulation were also surveyed. Telephone discussions with experts from Phillips Petroleum Co., Texaco, Inc., Scientific Software-Intercomp, Inc., Texas A & M University, and Morgantown Energy Technology Center provided information for the conclusion that implementation of a horizontal well model within the BOAST simulator can enhance BOAST to simulate the oil production from wells with horizontal laterals.

BOAST MODIFICATION

A horizontal well model was installed in the source code of the BOAST reservoir simulator. A new subroutine "NODESH" was created to read the horizontal well information. The total number of grid blocks containing the horizontal wellbore needs to be read in first, followed by x, y, z coordinates; productivity index; and bottomhole pressure for each grid block containing this well. More than one horizontal well and/or vertical well can be read in without limitations.

The existing subroutine "QRATE" was modified to compute the well rate and/or wellbore pressure for both horizontal and vertical wells. Similar to the treatment to the vertical well model within BOAST, this horizontal well model can be run under either rate or pressure constraints. Under the constraint of the constant production/injection rate, the wellbore pressure is back calculated from the assigned flow rate. The pressure constraint in the horizontal well model is treated in two ways: explicit pressure or implicit pressure. The flow rate under the explicit pressure constraint is calculated for each grid block containing the horizontal wellbore, based on its mobility ratio and formation volume factor. Under the implicit pressure constraint, the pressure matrix derived from the diffusivity equations is modified before being solved. The well rate is then calculated using the modified subroutine "PRATEO."

The approach to simulate the well performance above (or in the original BOAST simulator), under the rate constraint, is closed to the "uniform-flux" condition, in which the wellbore rates in different wellbore blocks are about the same and the wellbore pressure could be different from block-to-block. Since most drain holes are drilled and cased, an infinite-conductivity drain hole is closer to reality than a uniform-flux wellbore. Therefore, a new option of infinite-conductivity was added into the horizontal well model. The infinite-conductivity condition translates mathematically into a uniform-pressure (or uniform potential) condition at the well. This means that the flux at different points of the well is determined in such a way that the potential is uniform through the wellbore. To calculate these fluxes within wellbore blocks, two conditions must be applied: fluxes must sum to the required total rate, and a uniform potential at the well results. Mathematically, these conditions can be expressed as:

(a) When the oil flow rate (q_o) is specified:

$$q_o = \sum_{i=1}^{n} q_{oi}$$

$$= \sum_{i=1}^{n} [(\frac{k_r}{B\mu})_{oi}(PID)_i \ (P_i - P_{wf})] \qquad (1)$$

where q_{oi} is the flow rate in the ith wellbore block;

k_r, B, μ, and PID are relative permeability, formation volume factor, viscosity, and productivity index, respectively;

n is the number of blocks containing horizontal wellbore; and

P_i, P_{wf} are the ith wellblock pressure and bottomhole pressures, respectively.

Since k_r, B, μ, and PID are known for each block, equation 1 can be rewritten as:

$$q_o = \sum_{i=1}^{n} D_i (P_i - P_{wf}) \qquad \text{where } D_i = \left(\frac{k_r}{B\mu}\right)_{oi} (PID)_i$$

$$= \sum_{i=1}^{n} D_i P_i - P_{wf} \sum_{i=1}^{n} D_i$$

$$P_{wf} = \frac{1}{\sum_{i=1}^{n} D_i} \left(\sum D_i P_i - q_o\right)$$

Once the bottomhole pressure is determined, the flow rate in each wellbore block can be calculated as:

$$q_{oi} = D_i \left(P_i - P_{wf}\right)$$

(b) When the total flow rate (q_t) is specified, a similar approach to it in (a) can be used:

$$q_t = q_{ot} + q_{wt} + q_{gt}$$

$$= \sum_{i=1}^{n} \left[\left(\frac{k_r}{B\mu}\right)_{oi} + \left(\frac{k_r}{B\mu}\right)_{wi} + \left(\frac{k_r}{B\mu}\right)_{gi}\right] (PID)_i (P_i - P_{wf})$$

$$= \sum_{i=1}^{n} C_i \left(P_i - P_{wf}\right)$$

$$= \sum_{i=1}^{n} C_i P_i - C_i P_{wf}$$

where subscripts p, w, and g indicate oil, water, and gas phases, respectively;

and $C_i = [(\frac{k_r}{B\mu})_{oi} + (\frac{k_r}{B\mu})_{wi} + (\frac{k_r}{B\mu})_{gi}](PID)_i;$

then

$$P_{wf} = \frac{1}{\sum_{i=1}^{n} C_i} (\sum_{i=1}^{n} C_i P_i - q_t)$$

and $q_{oi} = (\frac{k_r}{B\mu})_{oi} \; (PID)_i(P_i - P_{wf})$

$$q_{wi} = (\frac{k_r}{B\mu})_{wi} \; (PID)_i(P_i - P_{wf})$$

$$q_{gi} = (\frac{k_r}{B\mu})_{gi} \; (PID)_i(P_i - P_{wf})$$

VERIFICATION OF HORIZONTAL WELL MODEL

The horizontal well version of BOAST was successfully tested in two- and three-dimensional runs, with and without vertical wells. Different options including rate constraint, explicit pressure constraint, and implicit pressure constraint were also verified. Table 1 lists the well types, well constraints, and wellblock coordinates used in the four simulation tests of the horizontal well model.

To verify the numerical results of this horizontal well model, analytical formulas developed in two SPE papers were used as benchmark checks. Figure 1 shows a good agreement between simulation results of our model and Ozkan's analytical type curve published in SPE paper 16378.[1] The simulated horizontal well is 2,000 feet long in the center of 50 feet of pay zone and an infinite reservoir. The block productivity index value used in the simulation is 2.5. The remaining parameters assigned in the simulator are the same as those in the sample problem in SPE Paper 16378.

The other analytical formula compared is the pressure drawdown of a horizontal well in a semi-infinite reservoir published in SPE paper 14250.[2] This 500-foot horizontal well is in the middle of a formation which is 220 feet in thickness, 2,100 feet in the x-direction, and infinite length in the y-direction. Figure 2 shows the comparison between the simulation results obtained in this study and the analytical curve in example problem 1 in the paper.[2] A close match was obtained except during the first 0.2 hour and the time period between 10 to 300 hours. The discrepancy at the early time period might be due to the numerical error associated with the gridding and/or the neglecting of the gravity effect in developing the analytical formula. The disagreement during the flow time from 10 to 300 hours indicates that our simulation model is more sensitive to the reservoir boundary than the theoretical prediction. It was found through various simulations that the numerical results are sensitive to both the time step used and the size of grid blocks containing and closed to the horizontal wellbore. The productivity index used in each wellbore block can also shift the pressure response curve of a horizontal well in the pressure transient test.

The developed horizontal well model in the BOAST simulator appears capable of predicting the production behavior of the horizontal well after being compared with the published theoretical formula.

FIELD SIMULATION OF HORIZONTAL WELL PRODUCTION

Reservoir information and production data of volatile oilfield A, in Eddy County, New Mexico, were collected for use in field simulation. The production of field A is from the Permian (Lower Leonard) Abo Reef dolomite at a depth of about 6,200 feet. The main producing mechanism is gravity drainage which is supplemented by the injection of the residual gas into the gas cap. Because of the high gas-oil ratio (GOR) produced from the volatile oil, the rapid depletion of the reservoir pressure resulted in reduced ultimate oil recovery and gas coning which has become the most serious operating problem for field A. In addition to the drilling of infill wells, production from horizontal drain holes became the alternative.

Figure 3 shows part of field A. Horizontal well A was drilled in field A in 1979. The total length of the horizontal drain hole is 106 feet. Offset conventional wells B, C, and D were drilled and completed, ranging from 660 to 960 feet away, as shown in figure 3. Gas injection wells are north of well A, and water influx comes from the bottom aquifer on the south side and water injection wells on the east side. The oil production rate and produced GOR from 1979 to 1981 for wells A, B, C, and D are shown in figure 4. Production data after 1982 were collected directly from the field office.

In a 15x15x5 three-dimensional simulation, the production history of wells A, B, C, and D is being matched. In addition to the above four oil production wells, one gas injection well in the top layer and one water injection well in the bottom layer were assigned in the reservoir model to simulate the gas/water injection in the formation. The relative permeability measured from cores in field A was used as the initial input. The PVT values (viscosity, formation volume factor, and amount of dissolved gas) with pressure were obtained from a PVT correlation package developed by Lewis Tech Service. The oil rates of four production wells were input into the simulation models, whereas gas saturation, pay zone thickness, and gas/water injection rates were adjusted to match the produced GOR for all four production wells. After a history match is performed, the production of horizontal well A can be evaluated, and the best production strategy can be obtained.

REFERENCES

1. Ozkan, E., R. Raghavaw, and S. D. Joshi. Horizontal Well Pressure Analysis. Pres. at the SPE California Regional Meeting, May 1987. SPE paper 16378.

2. Goode, P. A., and R. K. M. Thambynayagam. Pressure Drawdown and Buildup Analysis of Horizontal Wells in Anisotropic Media. Pres. at the SPE Ann. Meeting, Las Vegas, September 1985. SPE paper 14250.

TABLE 1. - Verification runs of horizontal well model

	Dimension (XxYxZ)	Well No.	Well type[1]	Wellblock coordinate
A.	15x15x1	1	V, WI, R	(8,1,1)
		2	V, WI, R	(8,15,1)
		3	H, OP, R	(7,7,1),(8,8,1),(9,9,1)
B.	15x15x1	1	V, WI, R	(8,1,1)
		2	V, WI, R	(8,15,1)
		3	H, OP, PI	(7,8,1),(8,8,1),(9,8,1)
C.	11x11x1	1	V, WI, R	(6,1,1)
		2	V, OP, PE	(6,11,1)
		3	H, WI, R	(1,5,1),(1,6,1),(1,7,1)
		4	H, OP, PI	(11,5,1),(11,6,1),(11,7,1)
D.	9x5x5	1	H, OP, PI	(4,3,3),(5,3,3),(6,3,3)

[1] V = vertical well.
H = horizontal well.
OP = oil production well.
WI = water injection well.
R = rate constraint.
PE = explicit pressure constraint.
PI = implicit pressure constraint.

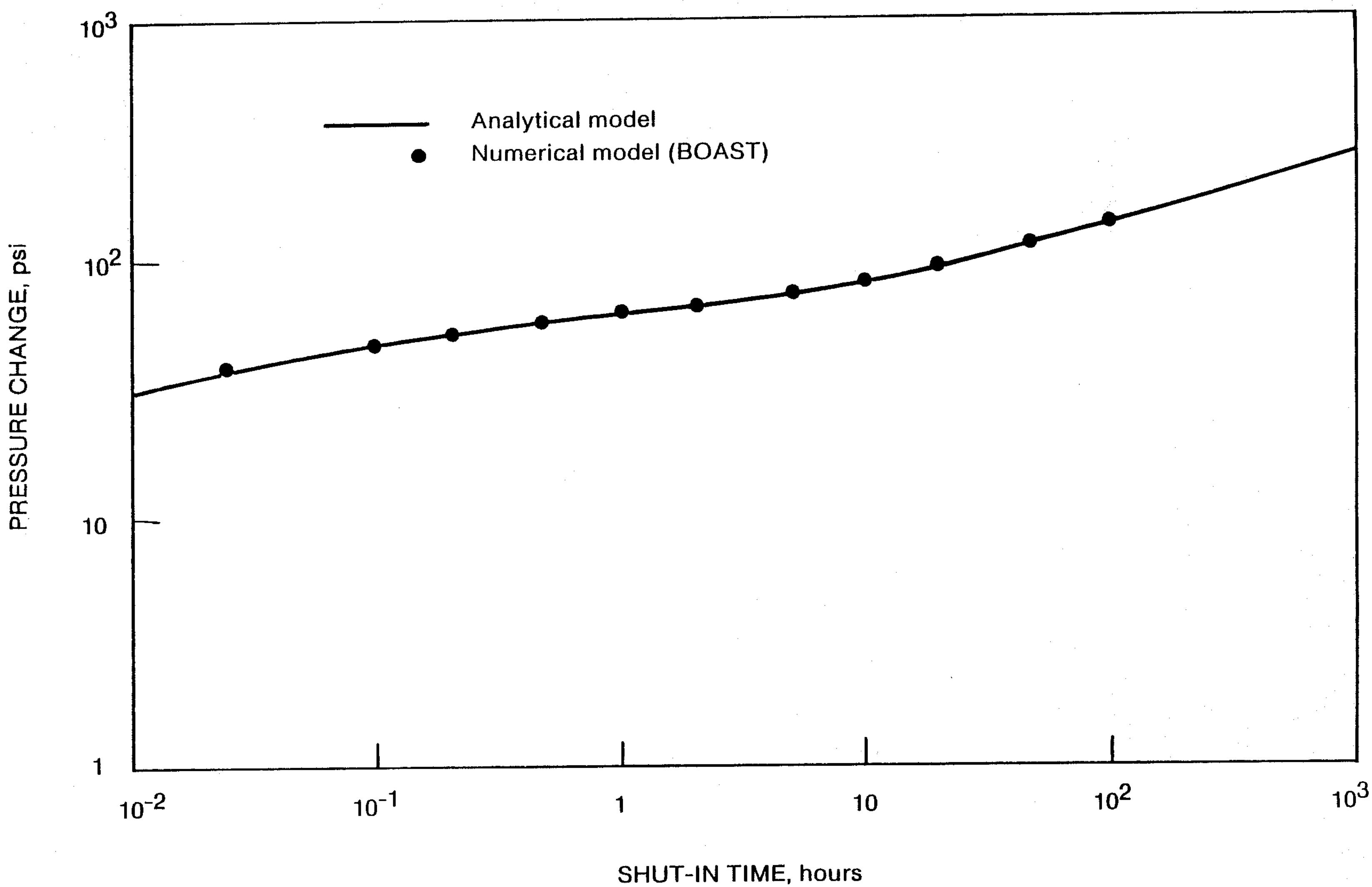

FIGURE 1. - Comparison between numerical and analytical models in pressure buildup test.

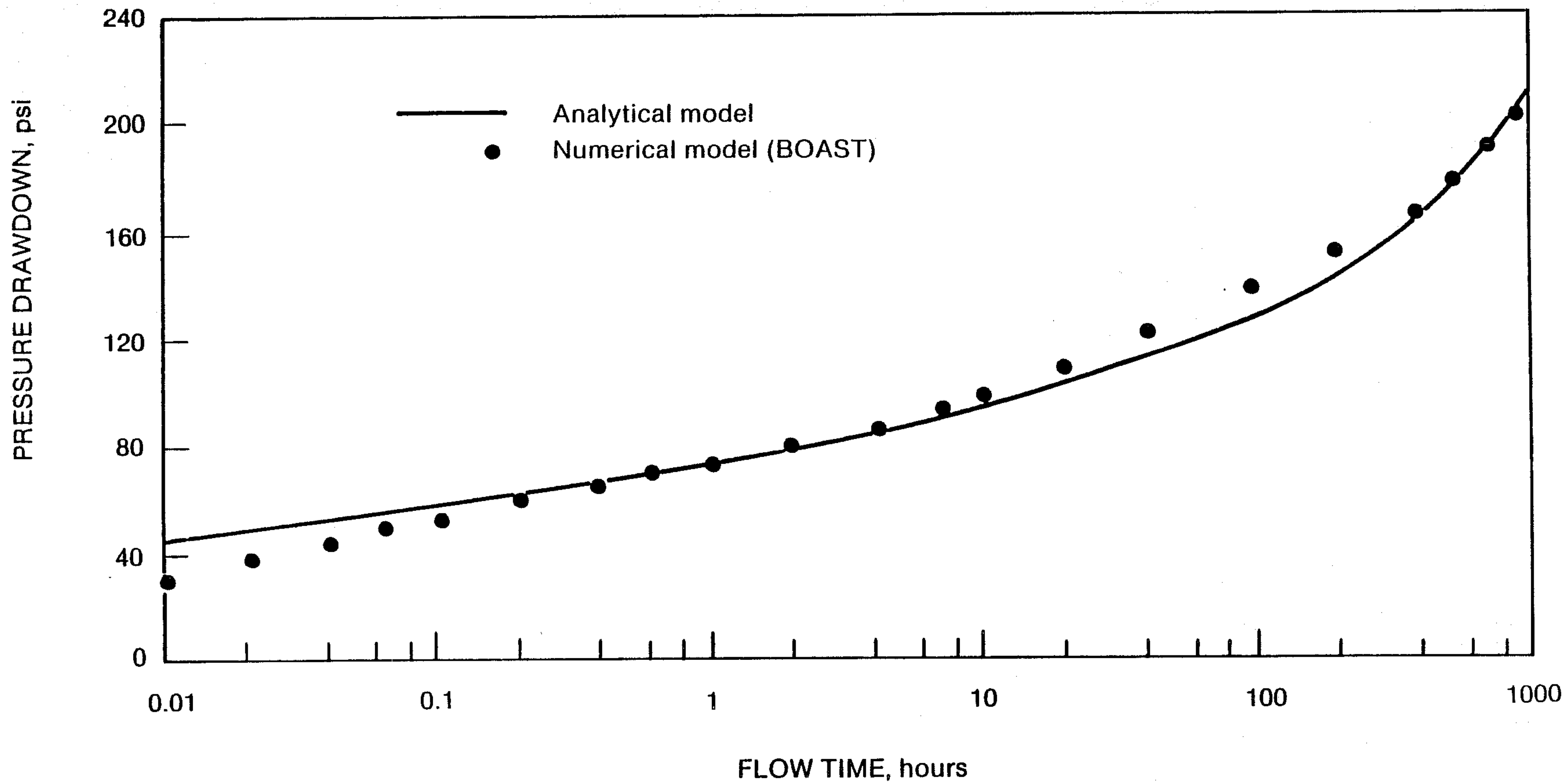

FIGURE 2. - Comparison between numerical and analytical models in pressure drawdown test.

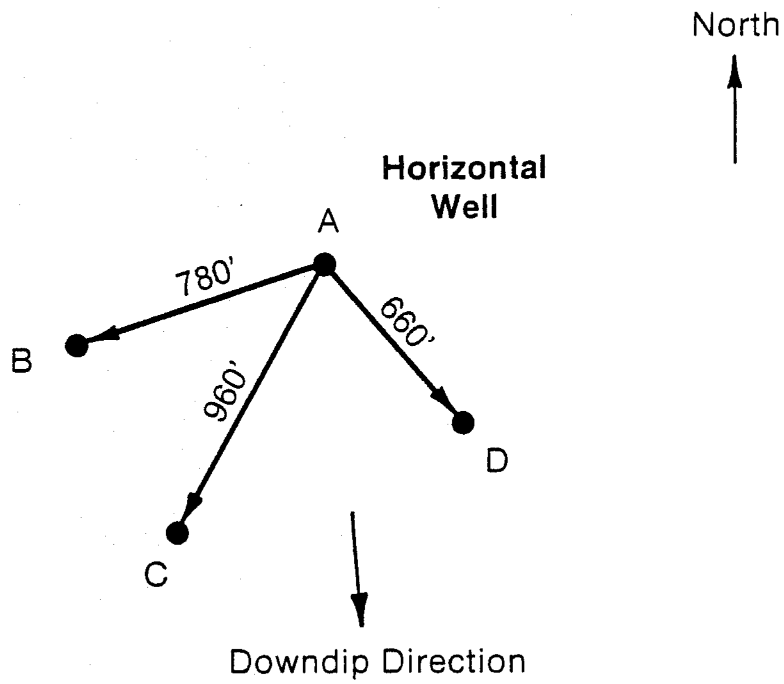

FIGURE 3. - Relative location of horizontal well A and offset conventional wells B, C, and D.

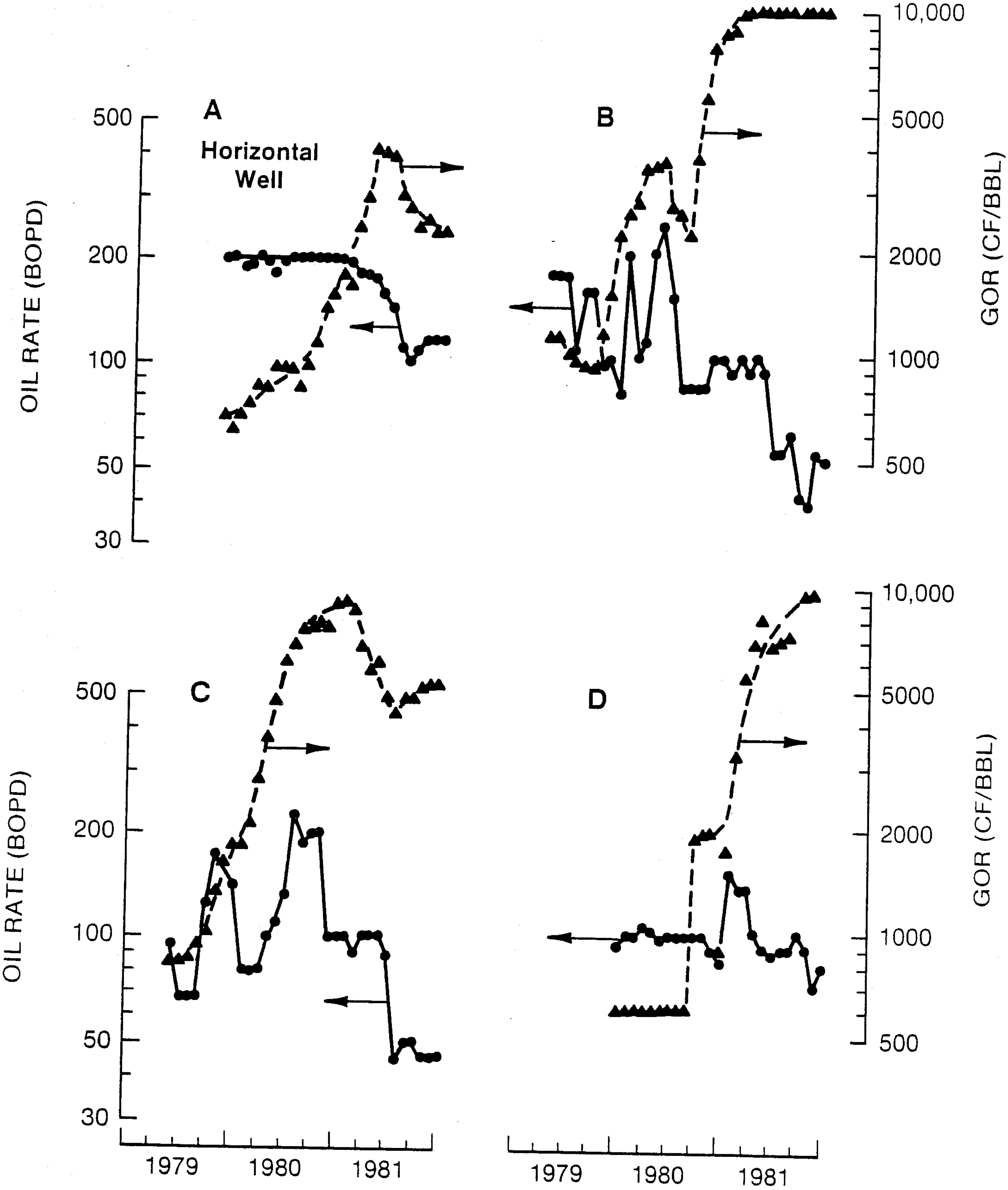

FIGURE 4. - Performance of horizontal well A and offset conventional wells B, C, and D.